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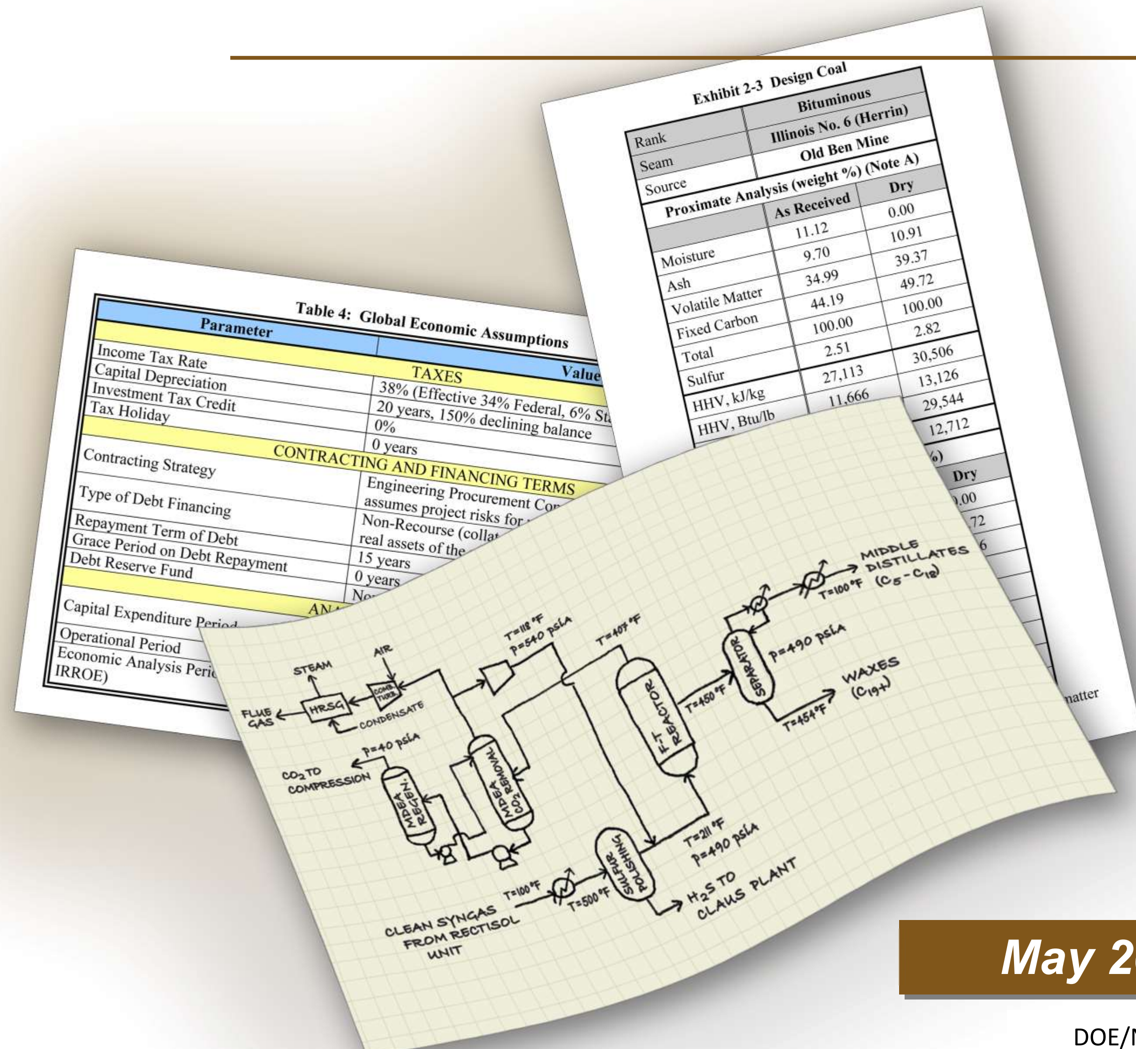
QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Carbon Dioxide Transport and Storage Costs in NETL Studies



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List of Exhibits

Acronyms and Abbreviations

AoR	Area of Review
CO_2	Carbon dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FE	Fossil energy
GW	gigawatt
Gt	Gigatonne (billion metric tons, 10^{12} kilograms)
IRROE	Internal rate of return on equity
INGAA	Interstate Natural Gas Association of America
mi^2	square mile
Mt	Million tonne, 10^9 kilograms
MVA	Monitoring, Verification, and Accounting
NETL	National Energy Technology Laboratory
O&GJ	Oil and Gas Journal
O&M	Operation and maintenance
psia	Pounds per square inch absolute
ROW	Right-of-way
T&S	Transport and storage
tonne	metric ton, 1000 kilograms

Executive Summary

The values to be used in systems studies sponsored by the National Energy Technology Laboratory (NETL) for estimating the cost of CO_2 pipeline transport and storage (T&S) (rounded to the nearest whole dollar) are shown in Exhibit ES-1. The basis for these values is discussed below.

Exhibit ES-1 Total transport and storage (T&S) costs for use in NETL system studies

Plant Location	Basin	T&S Value for System Studies (2011$/tonne)
Midwest	Illinois	11
Texas	East Texas	11
North Dakota	Williston	16
Montana	Powder River	24

Source: NETL

T&S cost information is used by NETL in their studies on the capture of CO_2 from electric power plants. Four geographic locations were selected (Exhibit 2-4) to model transportation and storage of captured CO_2: Midwest (Illinois Basin), Texas (East Texas Basin), North Dakota (Williston Basin), and Montana (Powder River Basin). In the base case, 3.2 million metric tons of CO_2 are captured and transported from a source in each of the basins modeled for storage costs. Cost of transportation is defined by a dedicated 100 km (62 mi) pipeline connecting the source of the captured CO_2 with a storage site. The modeled cost of transportation is $2.24 per tonne of CO_2.

Variability in overall T&S costs are found in the unique geology of the different reservoirs present in each of the four basins. Potential uncertainty associated with the cost of CO_2 storage in the reservoirs modeled in each basin is addressed with low-cost, base, and high-cost scenarios (Exhibit 2-5). Cost parameters for each cost scenario are modified to reflect a savings in cost or an additional cost burden due to potentially unique operational situations; for example, a reduction in 3-D seismic cost due to applied technology or an increase due to logistical challenges of seismic data acquisition.

Storage potential in a subsurface reservoir of captured CO_2 represents a resource that has yet to be proved. The cost of storage, which is the modeled cost to utilize this resource once proved, is the break-even cost to store a metric ton of CO_2. Storage costs posted in this guideline represent low-cost, base, and high-cost case scenarios at a cumulative storage potential of 25 billion metric tons (25 gigatonnes [Gt]), 50 Gt and 75 Gt (Exhibit 3-3). For the base case scenario and a cumulative storage potential of 25 Gt, the modeled cost to store one tonne of CO_2 in the Illinois Basin is $8.69. In the East Texas Basin this cost is $8.83 per tonne, in the Williston Basin it is $13.95 per tonne, and in the Powder River Basin it is $21.81 per tonne. Combined T&S base-case scenario cost at 25 Gt of potential storage is $10.93 per tonne in the Illinois Basin, $11.07 per tonne in the East Texas Basin, $16.19 per tonne in the Williston Basin, and $24.05 per tonne in the Powder River Basin. For system analysis studies at NETL, these cost values are rounded to $11 for the Illinois and East Texas Basins, $16 for the Williston Basin, and $24 for the Powder River Basin.

1 Objective

The purpose of this guideline is to estimate the cost of CO_2 pipeline transport and storage (T&S) in a deep saline aquifer for the plant locations used in the energy system studies sponsored by the National Energy Technology Laboratory (NETL). NETL is in the Office of Fossil Energy (FE) in the United States (U.S.) Department of Energy (DOE).

Transport costs are calculated using the FE/NETL CO_2 Transport Cost Model, [1] assuming a 100 km (62 mi) dedicated pipeline is used in each region to connect the CO_2 source (e.g., a power plant) to the CO_2 storage site. The FE/NETL CO_2 Transport Cost Model determines the pipeline diameter needed to transport a specified CO_2 mass flow rate (in this case an annual average of 3.2 million tonnes of CO_2) with or without boost pumps along the pipeline. The model then determines which combination of pumps and pipeline diameter gives the lowest overall cost in dollars per tonne of CO_2 transported.

Due to the variances in the geologic formations that make up saline aquifers across the U.S., the cost to store CO_2 can vary greatly depending on location. To account for these variances, region-specific results from the FE/NETL CO_2 Saline Storage Cost Model [2] are utilized to represent costs for the following plant locations and associated sedimentary basins used in NETL studies:

- Midwest – Illinois Basin
- Texas – East Texas Basin
- North Dakota – Williston Basin
- Montana – Powder River Basin

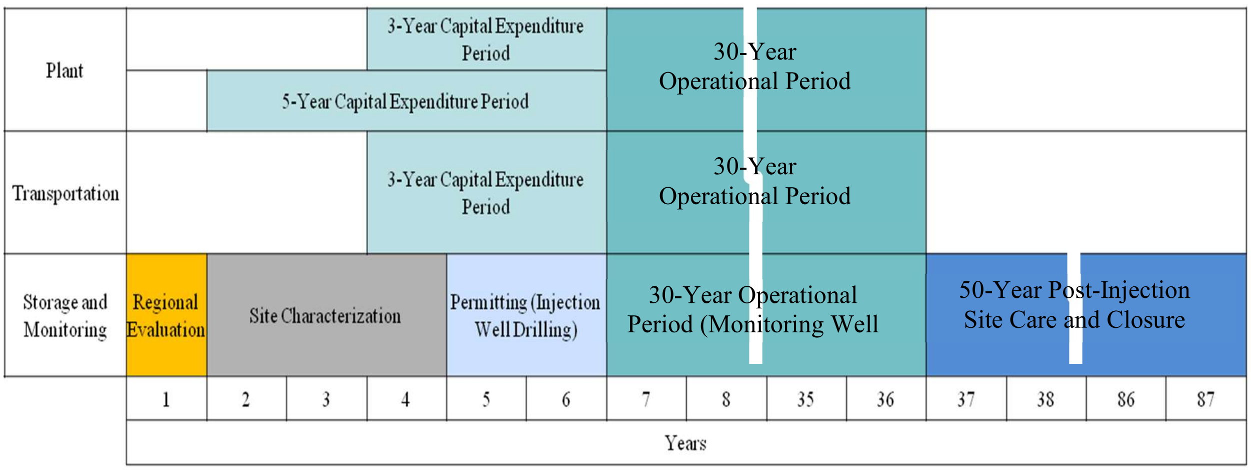
Variance also occurs within the geologic formations present in each of these basins. Three cost scenarios – low-cost, base, and high-cost – were developed to reflect variance within the geologic formations in each of the basins modeled.

The costs calculated by the FE/NETL CO_2 Saline Storage Cost Model cover all costs including capital costs, operating costs, financing costs, and taxes and are expressed in dollars per tonne of CO_2 stored. Costs were developed for all potential storage formations in each region, and the total mass of CO_2 that can potentially be stored in each formation was also calculated. Since the cheapest formations are likely to be the first to be used for storage (all other things being equal), the costs for all formations in a region were ranked from lowest to highest, and the cumulative mass of CO_2 that could be stored at that cost (or lower) was calculated. T&S costs were then determined for three levels of cumulative CO_2 storage in each region: 25, 50, and 75 billion tonnes. As a point of reference, the U.S. emits around 2 billion tonnes of CO_2 each year from the electric power sector and around 1 billion tonnes of CO_2 each year from industrial sector excluding emissions associated with electricity used by industrial operations. [3]

2 Approach

T&S costs are reported as first-year costs in \$/tonne of CO_2, increasing at a nominal rate of 3 percent per year, which is consistent with the general inflation rate assumed in NETL's baseline energy system studies. From the perspective of the CO_2 source (e.g., a power plant or other energy conversion facility), these costs are treated as a disposal cost for each tonne of CO_2 captured during the assumed 30-year operational period. From the pipeline and storage site's perspective, the costs of T&S represent the minimum price that these operators must charge so that they receive the revenue needed across the 30-year operational period to cover all their costs and provide their required internal rate of return on equity (IRROE). All costs are reported in 2011 dollars.

Exhibit 2-1 Timelines for construction and operations of plant, transport, and storage



Source: NETL

T&S costs are based on the CO_2 flow rate of one example plant: a daily maximum 11,000 tonne/day (12,000 ton/day), which translates into an annual average of 3.2 million tonnes per year assuming an 80 percent capacity factor. The sensitivity of transport costs based on flow rate, capacity factor, and pipeline length can be assessed using the FE/NETL CO_2 Transport Cost Model. A limited sensitivity analysis is presented in Section 3.1. The sensitivity of storage costs based on flow rate and capacity factor can be determined using the FE/NETL CO_2 Saline Storage Cost Model, but the sensitivity of the model to these parameters was not investigated in this guideline.

2.1 Transport Costs

The FE/NETL CO_2 Transport Cost Model is a mathematical model that estimates the cost of transporting liquid CO_2 using a pipeline. The FE/NETL CO_2 Transport Cost Model is an updated version of the CO_2 pipeline cost model at NETL. [4] Costs are estimated for a single point-to-point pipeline, which may have pumps along the pipeline to boost the pressure. The model includes the capital costs for purchasing and installing the pipeline, a surge tank, a pipeline control system and, if economical, the boost pumps. The FE/NETL CO_2 Transport Cost

Model accounts for the operation and maintenance (O&M) costs for the pipeline and pumps and the cost of the electricity used to power the pumps. The FE/NETL CO_2 Transport Cost Model also has a financial model with debt, equity, depreciation, and taxes. The model can determine the price of CO_2 (in dollars per tonne of CO_2 transported) that provides investors with their desired minimum IRROE. This price is referred to as the break-even price of CO_2 in this guideline. The break-even price is also the minimum cost of transporting CO_2 from the perspective of the CO_2 source.

For the analysis in this guideline, it is assumed that CO_2 is provided by the CO_2 source at a pressure of (2,200 psig), and the cost and energy requirements of compression are assumed by the CO_2 source. CO_2 is in a dense phase liquid state at this pressure, which is desirable for transportation.

CO_2 exits the pipeline terminus at the CO_2 storage site at a pressure of 1,200 psig. This exit pressure specification ensures that CO_2 remains in a dense phase liquid state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation changes. Costs for additional compression that may be required for injection in a particular formation is included as part of storage costs.

For this analysis, a pipeline length of 100 km (62 mi) is assumed. The FE/NETL CO_2 Transport Cost Model can estimate the minimum pipeline diameter needed to transport the CO_2 this distance without any pumps to boost the pressure. The model can also determine if a smaller diameter pipe can be used if one or more pumps are used at equal intervals along the pipeline to boost the pressure from 1200 psig at the pump inlet to 2200 psig at the pump outlet.

The FE/NETL CO_2 Transport Cost Model uses an iterative procedure to determine the diameter necessary to sustain a 1,000 psia pressure drop over the specified pipeline length, or pipeline segment length, if pumps are installed along the pipeline. The model rounds up the diameter to the nearest standard pipe diameter. The pipeline diameter was determined based on the CO_2 output produced by the CO_2 source when it is operating at full capacity (100 percent utilization factor) rather than at average capacity.

CO_2 transport costs are broken down into capital and operating expenses. The capital expenses include the costs for the pipeline, a surge tank, a pipeline control system, and the boost pumps (if used). The operating expenses include O&M costs for these pieces of equipment and the cost of the electricity used by the boost pumps.

The FE/NETL CO_2 Transport Cost Model provides three equations for calculating the capital costs for the pipeline. The three equations all used pipeline capital costs reported in the *Oil and Gas Journal's* (O&GJ) annual *Pipeline Economics Report* for existing natural gas, oil, and petroleum pipeline projects. [5] The O&GJ reported capital costs in four categories: 1) materials, 2) labor, 3) right of way (ROW) and damages, and 4) miscellaneous. The materials category included the cost for pipe, pipe coating, and cathodic protection. The miscellaneous category included costs for surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction (AFUDC), administration and overheads, and regulatory filing fees. One set of equations for pipeline capital costs was developed by Parker [6] using cost data from 1991 to 2003; these equations give costs in 2000 dollars. A second set of equations for pipeline capital costs was developed by McCoy and Rubin [7] using cost data from 1995 to 2005; these equations give costs in 2004 dollars. The third set of equations for pipeline capital costs was developed by Rui et al. [8] using cost data from 1992 to 2008; these equations give costs in 2008 dollars. While the three sets of equations have different functional forms, they all calculate capital costs as a function of pipeline length and diameter. The capital costs for all three sets of equations were adjusted to 2011 dollars using a variety of price indices. [1] The resulting capital costs are for natural gas pipelines. CO_2 pipelines operate at higher pressures than natural gas pipelines, so they require a thicker pipe wall, which affects the cost. The capital costs for materials and labor were adjusted, depending on the pipe diameter, using factors developed by ICF International. [9]

The costs for a surge tank and pipeline control system were taken from an earlier NETL study. [4] These costs were in 2000 dollars and were adjusted to 2011 dollars using appropriate price indices. [1] The capital costs for a boost pump were determined using an equation provided by McCollum and Ogden. [10] This equation needs the power requirements for the boost pumps and McCollum and Ogden [10] also provide an equation for estimating the power requirement based on the CO_2 mass flow rate and pressure increase through the pump. The pump capital costs were in 2005 dollars and were adjusted to 2011 dollars using appropriate price indices. [1]

The O&M costs for the pipeline were based on a value provided in Heddle et al. [11] These were in 1999 dollars and were adjusted to 2011 dollars using appropriate price indices. [1] The O&M costs for the remaining pieces of equipment were assumed to be 4 percent of the capital costs on an annual basis. The price of electricity used to estimate the cost of the electricity used by the pumps was assumed to be the national average electricity price for electricity provided to commercial operations in 2011. [12]

As discussed above, the FE/NETL CO_2 Transport Cost Model has a financial model with debt, equity, depreciation, and taxes. The model can determine the price of CO_2 (in dollars per tonne of CO_2 transported) that provides investors with their desired minimum IRROE. To use the financial model, a number of parameters must be specified. For this evaluation, it was assumed that it takes 3 years to complete the construction of the pipeline and that the pipeline operates for 30 years. The following financial parameters were used, which match the low-risk business scenario for an investor-owned utility [13]:

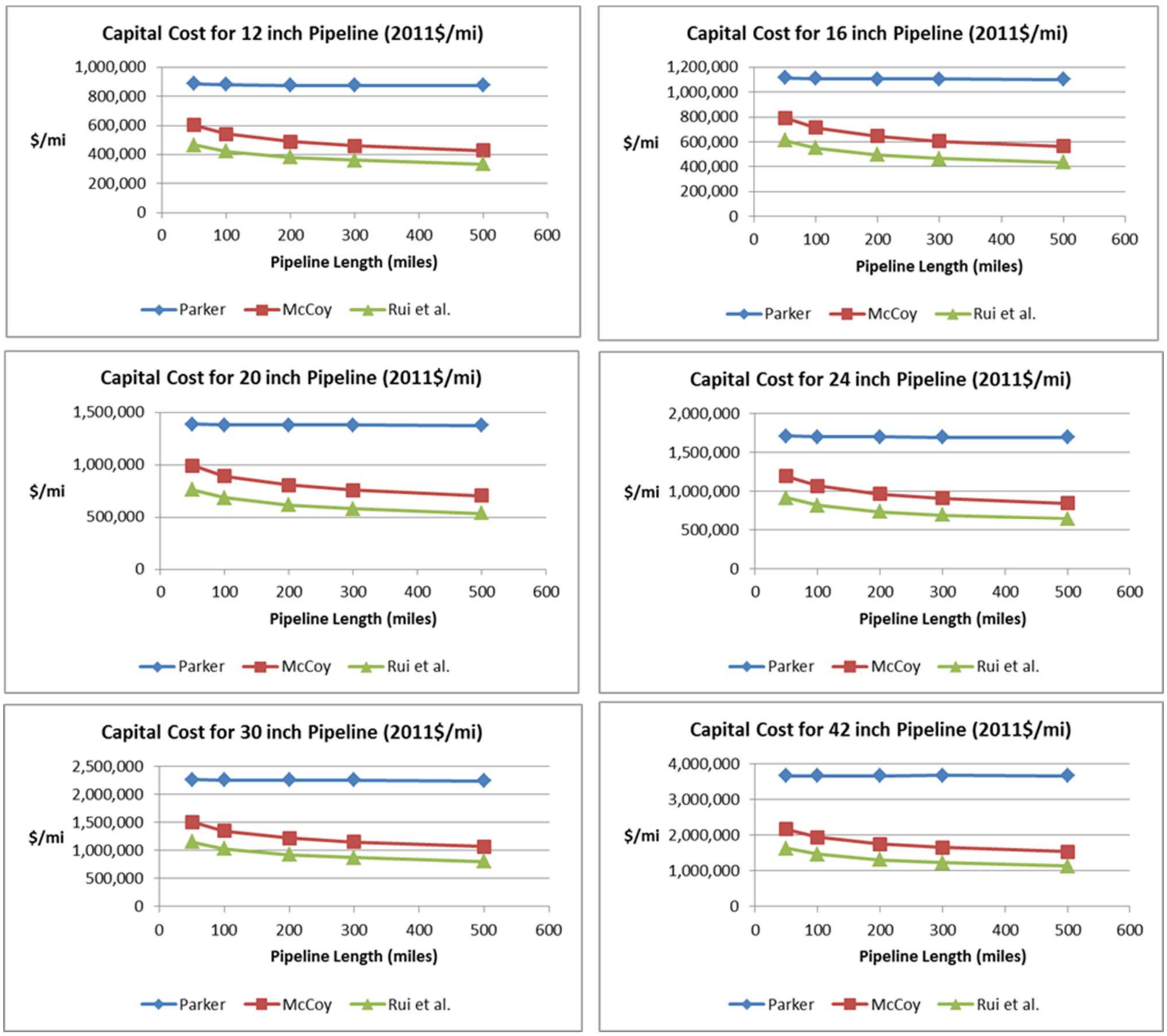
- Escalation of all costs at a rate of 3% per year
- Debt to equity ratio of 50%/50%
- Interest rate on debt of 4.5%/year
- Minimum IRROE of 12%
- 30-year operational period

The FE/NETL CO_2 Transport Cost Model includes a project contingency calculated for all capital costs. NETL guidelines for cost estimating [14] recommend using a project contingency between 15 percent and 30 percent for the budgetary-level type cost estimate that is provided by the FE/NETL CO_2 Transport Cost Model. The lower value of 15 percent was used for the analysis in this guideline, because the pipeline costs provided by the O&GJ may include contingency and some taxes.

The FE/NETL CO_2 Transport Cost Model determines the returns to the owner using a weighted average cost of capital methodology. [1]

The three sets of equations for natural gas pipeline capital costs give different results as illustrated in Exhibit 2-2, which presents the cost per mile for different pipeline lengths and diameters. In general, the equations from Parker [6] give the highest cost followed by the equations from McCoy and Rubin [7] and then Rui et al. [8] The equations from Parker [6] give significantly higher costs than the other two equations.

Exhibit 2-2 Natural gas pipeline capital costs using different equations



Source: NETL

To determine which of these three sets of equations to use in the analysis for this guideline, a comparison was made to pipeline capital cost data from a variety of sources. The capital costs for a CO_2 pipeline per inch (diameter) and mile (length) including contingency range are as follows for the different sets of equations:

- Parker: $85,000/in-mi (12 in pipe) to $120,000/in-mi (42 in pipe)
- McCoy: $65,000/in-mi (50 mile long pipe) to $46,000/in-mi (500 mile long pipe)
- Rui: $50,000/in-mi (50 mile long pipe) to $35,000/in-mi (500 mile long pipe)

The capital costs per inch-mile using the equations from Parker [6] increase with increasing diameter but are relatively insensitive to the length of the pipeline. The capital costs per inch-mile using the equations from McCoy and Rubin [7] increase somewhat with increasing diameter but decrease with increasing pipeline length. The capital costs per inch-mile using the equations from Rui et al. [8] show the same type of behavior as the equations from McCoy and Rubin. [7]

These costs were compared to contemporary pipeline costs quoted by industry experts, such as Kinder-Morgan and Denbury Resources. Exhibit 2-3 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet Meeting in 2009. [15] It is not known if these rule-of thumb estimates include contingencies. As shown, the costs using the equations from Parker [6] are on the high end of this range, while the costs using the equations from McCoy and Rubin [7] fall on the low end of this range, and the costs using the equations from Rui et al. [8] tend to fall below this range.

Exhibit 2-3 Kinder-Morgan pipeline cost metrics

Terrain	Capital Cost ($/inch-Diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150’-200’ depth)	$700,000

A further comparison was made to cost data for two Denbury CO_2 pipelines. The first is the Green pipeline with the following characteristics.

- Location: Southeast United States
- Pipeline length: 314 miles
- Pipeline diameter: 24 inches
- CO_2 flow capacity: 42,320 tonne/day
- Capital cost: About 660 million dollars according to trade journals

  About 884 million dollars excluding capitalized interest according to the annual report
- Status: Completed around 2010

Assuming the capacity factor is 80 percent for this pipeline, the FE/NETL CO_2 Transport Cost Model determines that a 24-inch pipeline of this length would need 2 pumps. The capital cost for this project is estimated by the model to be as follows:

- Using Parker eq.: 740 million dollars
- Using McCoy eq.: 435 million dollars
- Using Rui eq.: 370 million dollars

The result using the Parker equations [6] exceeds the value in trade journals but is less than the value in the annual report. The results from the McCoy and Rubin [7] and Rui et al. [8] equations are significantly less than both published capital costs.

The second CO_2 pipeline is the Greencore pipeline with the following characteristics:

- Location: Wyoming
- Pipeline length: 232 miles
- Pipeline diameter: 20 inches
- CO_2 flow capacity: 38,280 tonne/day
- Capital cost: About 285 million dollars according to trade journals

  About 135 million dollars for second half of project according to annual report
- Status: Completed in 2012 or 2013

Assuming the capacity factor is 80 percent for this pipeline, the FE/NETL CO_2 Transport Cost Model determines that a 20-inch pipeline of this length would need 4 pumps. The capital cost for this project is estimated by the model to be as follows:

- Using Parker eq.: 430 million dollars
- Using McCoy eq.: 170 million dollars
- Using Rui eq.: 135 million dollars

The result using the Parker equations [6] exceeds the value in trade journals. The results from the McCoy and Rubin [7] and Rui et al. [8] equations are less than the published capital costs.

These results indicate that the equations from Parker [6] and McCoy and Rubin [7] give costs that are closest to published CO_2 pipeline costs. The equations from Parker [6] tend to give costs on the high side, while the equations from McCoy and Rubin [7] tend to give costs on the low side. To be conservative (i.e., to err on the side of over-estimating CO_2 transport costs), the equations from Parker [6] were used in the analysis for this guideline.

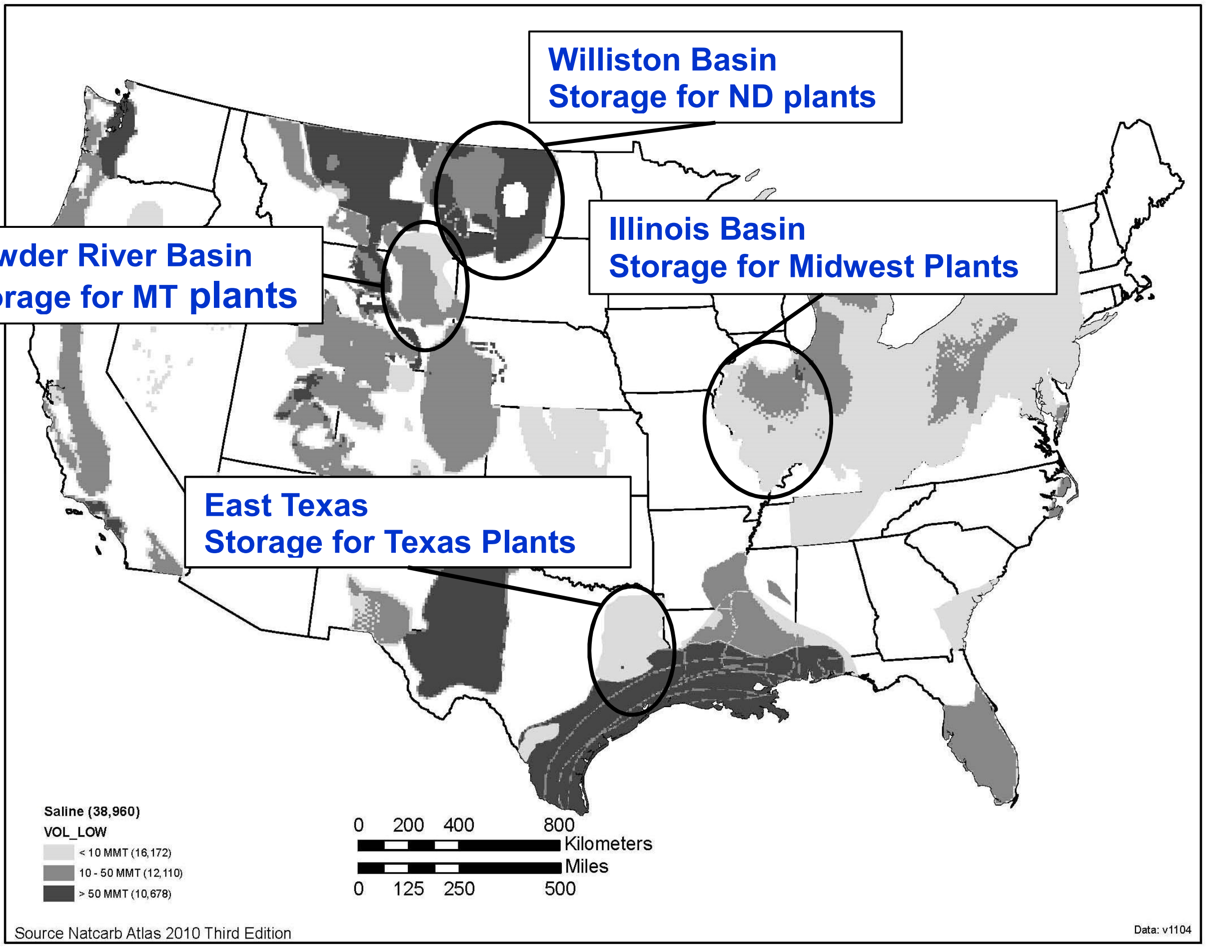
2.2 Storage and Monitoring Costs

Storage and monitoring costs were estimated using the FE/NETL CO_2 Saline Storage Cost Model. This model is a spreadsheet-based tool that estimates the break-even price for storing CO_2 in a deep saline aquifer from the perspective of the owner of a CO_2 storage site. This break-even price is also the minimum cost for storing captured CO_2. The FE/NETL CO_2 Saline Storage Cost Model includes the cost of complying with key regulations. In order to inject CO_2 into the subsurface for the purpose of storing CO_2 in a saline aquifer, the site owner must comply with the U.S. Environmental Protection Agency (EPA) regulations for Class VI injection wells under EPA's Underground Injection Control Program, which is authorized under the Safe Drinking Water Act. The site owner must also comply with monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule, which is authorized under the Clean Air Act.

The majority of well, technology, and labor cost data are from EPA's economic analysis of the Class VI and Subpart RR regulations and are in 2008 dollars. Except for groundwater wells or vadose zone wells, the cost of all wells in the model is based on the 2006 API-Joint Association Survey. Some cost data are based on conversations with industry personnel while at conferences. Costs posted in the model are updated as new information becomes available.

Results from the FE/NETL CO_2 Saline Storage Cost Model for storage and monitoring costs were aligned with the NETL system studies by taking the four generic plant locations and overlaying them with possible storage basins from the cost model. This couples generic system study plant locations of Midwest, Texas, North Dakota, and Montana with the Illinois, East Texas, Williston, and Powder River Basins, respectively, as shown in Exhibit 2-4.

Exhibit 2-4 Location of four basins selected for this study



Source: NETL

Inputs to the FE/NETL CO_2 Saline Storage Cost Model that have a significant influence on cost include financial parameters, timelines for the various stages of storage, drilling or monitoring activities in stages, and selection of financial responsibility instruments.

The financial parameters match the high-risk business scenario for an Investor Owned Utility and include:

- Debt to equity ratio of 45%/55%
- Interest rate on debt of 5.5%/year
- IRROE of 12%
- Escalation rate of 3%
- Modified trust fund that grows at an annual rate over the period of injection operations
- Project contingency factor of 15%
- Process contingency factor of 20%

In the FE/NETL CO_2 Saline Storage Cost Model, a storage project is divided into six stages. The timelines and important activities impacting costs for these stages are:

- Regional evaluation and initial site selection: 1 year
- Site characterization: 3 years
  - Four sites simultaneously undergo characterization, each having a 2-D seismic survey covering the estimated Area of Review (AoR) and one strat-well drilled to collect relevant reservoir data.
  - The successful site has an additional strat-well drilled plus a 3-D seismic survey covering the AoR; pore-space rights and property access are also leased.
- Permitting: 2 years
  - Includes submittal of required plans (AoR & Corrective Action, Testing & Monitoring, Injection Well Plugging, Post-Injection Site Care & Site Closure, Emergency & Remedial Response) for Class VI injection well permit, permission to drill injection wells, drilling and completion of injection wells, incorporation of new data from injection wells into reports, resubmission of reports, and final permission to inject captured CO_2.
  - Demonstrate financial responsibility.
- Operations: 30 years
  - Injection of 3.2 Mt of CO_2 per year for 30 years.
  - Installation of buildings, surface equipment, monitoring wells, and other monitoring equipment per submitted testing and monitoring plan.
  - AoR review occurs every five years with 3-D seismic.
  - Plugging injection wells at conclusion of injection operations.
  - Payment into modified trust fund to cover financial responsibility requirements for corrective action, injection well plugging and post-injection site care, and site closure. Emergency and Remedial Response covered by separate insurance.
- Post-injection site care and site closure: 50 years
  - Monitoring continues per submitted testing and monitoring plan.
  - Monitoring wells are plugged and other monitoring equipment removed at the conclusion of post-injection site care.
  - Costs during this period are covered by the storage site operator's trust fund.
- Long-term stewardship: This stage is not explicitly included in the model. The possible financial implication of long-term stewardship is included in the model as a state-sponsored trust fund that the storage operator pays into during operations.

Cost variability is also present within a basin due to the changing geologic character of a particular formation in which a CO_2 storage operation will be developed. Three cost scenarios were established to model this variability: low-cost, base, and high-cost. Changes in modeling parameters between low-cost, base, and high-cost case scenarios are illustrated in Exhibit 2-5.

Exhibit 2-5 Modeling parameters for low-cost, base, and high-cost cases distance

Parameter Modeled	FY 12 Model Run	Model Parameters for Baseline CO_2 Storage Costs - FY13 Update		
		Low Cost Case	Base Case	High Cost Case
Financial Responsibility	Modified Trust Fund	Modified Trust Fund		
Trust Fund Growth Rate	5%	7%	5%	3%
Storage Coefficient	P50	P90	P50	P10
Debt/Equity Ratio	45/55 - based on High Risk scenario for an Investor Owned Utility (IOU)	45/55 - based on High Risk scenario for an Investor Owned Utility (IOU)		
Financials	Cost of Debt = 5.5% Cost of Equity = 12% Escalation = 3%	Cost of Debt = 5.5%; Cost of Equity = 12%; Escalation = 3%		
Post-Injection Site Care & Site Closure	50 years, default period in Class VI regulations	25 years	50 years, default period in Class VI regulations	50 years, default period in Class VI regulations
Site Characterization	3 years - 4 sites	3 years - 2 sites	3 years - 4 sites	6 years - 4 sites
Permitting	2 years	2 years	2 years	4 years
3-D Seismic	$160,000/mi^2	$100,000/mi^2	$160,000/mi^2	$220,000/mi^2
Monitoring Wells	In Reservoir: 1 well/4 mi^2 Above Seal: 1 well/2 mi^2 In reservoir wells dual completed above seal.	In Reservoir: 1 well/8 mi^2 Above Seal: 1 well/4 mi^2 In reservoir wells dual completed above seal. Four dual completed monitoring wells pressure front.	In Reservoir: 1 well/4 mi^2 Above Seal: 1 well/2mi^2 In reservoir wells dual completed above seal. Four dual completed monitoring wells in pressure front.	In Reservoir: 1 well/4 mi^2 - no dual completions. Above Seal: 1 well/2 mi^2 Four dual completed monitoring wells in pressure front.
Corrective Action	1 well/4 mi^2 requiring corrective action.	1 well/8 mi^2 requiring corrective action.	1 well/4 mi^2 requiring corrective action.	2 wells/mi^2 requiring corrective action.
Water Withdrawal/Disposal	None	None	None	$2.00 per tonne CO_2 stored

Source: NETL

Costs increase from the low-cost scenario to the high-cost scenario due to changes in the following parameters listed in Exhibit 2-5:

- Rate of return on the trust fund decreases, increasing the cost to the operator to maintain a suitable balance in the modified trust fund to meet regulatory requirements.
- Storage coefficient decreases, reducing the storage volume per unit area and increasing the plume size and associated monitoring costs.
- Post-injection site care and site closure period of 25 years in the low case increases to the default time period of 50 years for the base and high-cost cases, increasing monitoring and financial responsibility costs.
- The number of years to complete site characterization and permitting are increased in the high-cost case, delaying operations and positive cash flow from injection revenue.
- 3-D seismic costs increase from $100,000 per square mile to $220,000 per square mile.
- The number of monitoring wells drilled increase because well spacing for monitoring wells in the plume area decrease from low to base case, both of which utilize the opportunity to dual complete these wells in the reservoir and above the seal where possible. The high-cost case has the well spacing of the base case but does not dual complete any monitoring wells in the plume area, increasing the number of above seal wells drilled. All three scenarios have four dual completed monitoring wells for the pressure front area.

- Increasing number of wells requiring corrective action increases the value of financial responsibility and cost to perform this activity.
- Water withdrawal from the storage reservoir and subsequent treatment and disposal in the high-cost case scenario adds another level of costs to operations. [16] A methodology to model costs associated with water withdrawals from the storage reservoir, surface treatment, and subsequent disposal is under development and testing. This cost is included in the high-cost case scenario to reflect the possibility that an operator may adopt water withdrawals to maintain suitable reservoir pressures and/or control the areal extent of the plume. [17]

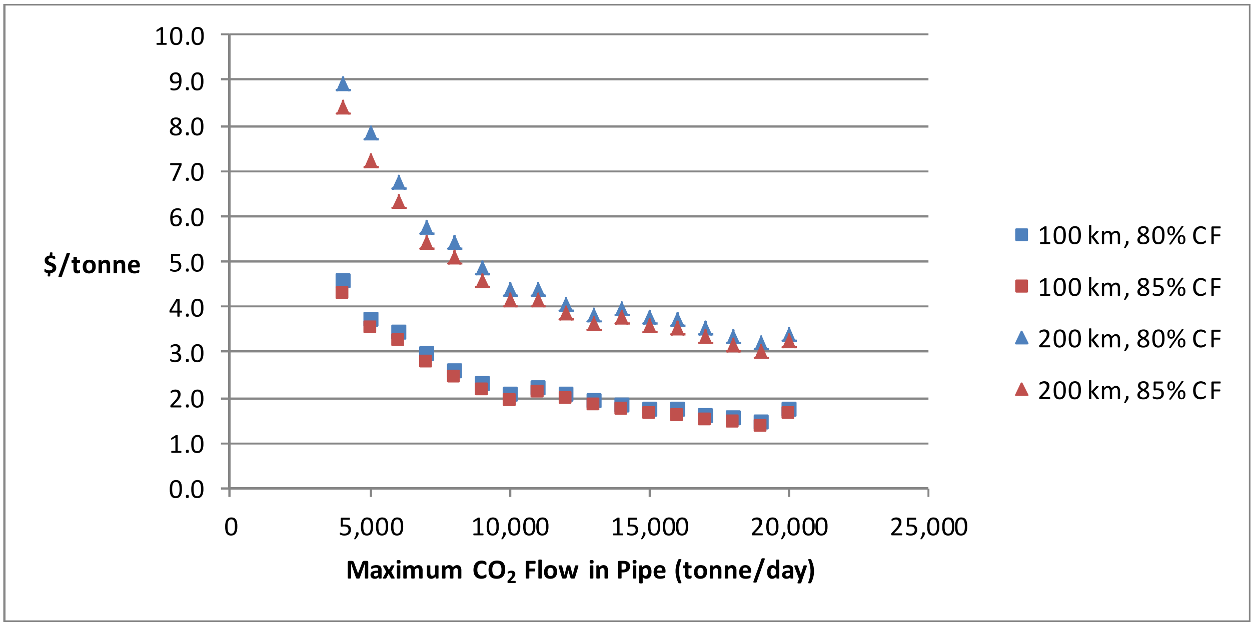
3 Results

3.1 Transport Costs

The FE/NETL CO_2 Transport Cost Model was used to estimate the first-year break-even price (also the minimum cost) for transporting a maximum daily flow of 11,000 tonne/day of CO_2 with a capacity factor of 80 percent a distance of 100 km (62 mi) with 1,000 psi pressure drop. The model estimates that the lowest cost configuration will have a 12-inch pipe diameter and one boost pump. For this configuration, the estimated capital cost is $67 million in 2011 dollars, and the estimated annual operating and maintenance cost (O&M) is $1.5 million per year in 2011 dollars. The resulting first-year break-even price (or minimum cost) for CO_2 transport is $2.24/tonne of CO_2 in 2011 dollars.

This value will be used in NETL Energy System Studies as a reasonable approximation for CO_2 transport costs for all plants regardless of the capacity factor and CO_2 capture rates. Exhibit 3-1 shows the sensitivity of the minimum transport cost to capacity factor and CO_2 transport rate. Costs are shown for pipelines of 100 km (62 mi) and 200 km (124 mi). The plot indicates that the higher the flow rate, the lower the unit cost, although there are some small discontinuities when the pipeline configuration changes (such as at 11,000 tonne/day for the 100 km long pipeline when the number of pumps increases from zero to one). The plot indicates that increasing the capacity factor decreases the cost, but this effect is relatively small. The plot also indicates that the longer the pipeline the higher the cost, with the cost being roughly proportional to the length.

Exhibit 3-1 Sensitivity of transport costs to plant and distance assumptions

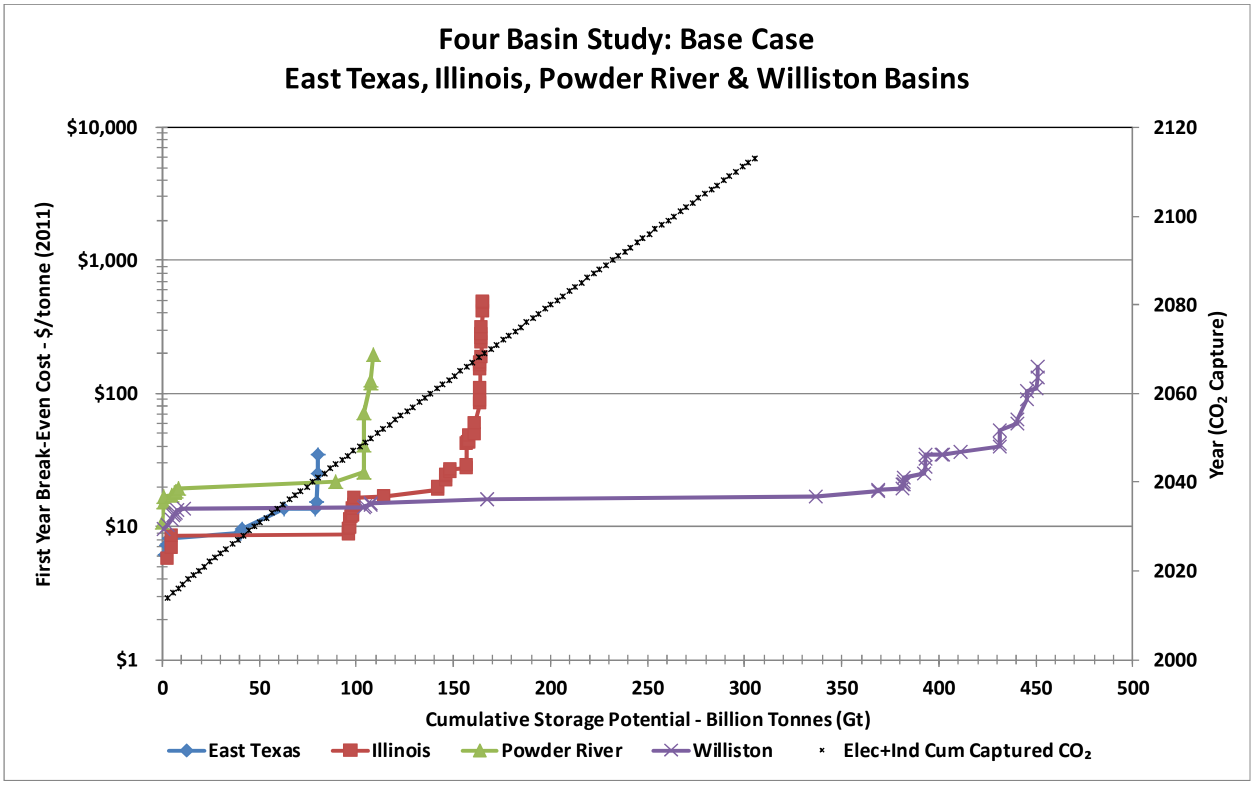


Source: NETL

3.2 Storage and Monitoring Costs

Cost supply curves are plotted in Exhibit 3-2 for the East Texas, Illinois, Powder River, and Williston basins. This figure presents the mass of CO_2 that can be stored theoretically in each basin at a given price of CO_2. The price is the break-even price of CO_2 for a storage project in each basin (i.e., the price of CO_2 where the net present value for the project is zero). Each basin includes two or more storage formations. The curves in Exhibit 3-2 represent the storage resource potential for the Paluxy and Woodbine formations in the East Texas Basin; the Mt. Simon, St. Peter, and Knox formations in the Illinois Basin; the Red River, Mission Canyon, and Cambrian Sandstone formations in the Williston Basin; and the Minnelusa, Muddy, and Madison formations in the Powder River Basin. Also plotted in Exhibit 3-2 is a projection, based on EIA data, [3] of the cumulative mass of CO_2 emissions from the electric power and industrial sectors that can be captured over the next century (305 Gt), assuming 90 percent of all CO_2 emissions are captured.

Exhibit 3-2 CO_2 cumulative storage potential cost supply curves



Source: NETL

The storage potential for each formation depends upon the inherent porosity of each formation and upon a storage coefficient. The cost variability in the modeling is in part due to a change in the storage coefficient, which is the percentage of the formation's brine-filled pore volume that may be occupied by CO_2. The storage coefficient depends on the depositional environment and the structural setting. [18] The storage resource potential for each formation in the basins shown previously in Exhibit 2-4 is partitioned into three structural settings: dome, anticline, and regional dip. Depositional environments for the clastic formations are eolian (Minnelusa), shallow clastic shelf (Muddy), peritidal (St. Peter), strand plain (Mt. Simon), fluvial (Woodbine), and delta (Paluxy). Depositional environments for the carbonate formations are shallow shelf (Knox, Madison, and Mission Canyon).

The storage resource potential for any particular formation reflects the areal extent of the formation as well as its thickness, porosity, and storage coefficient. In the FE/NETL CO_2 Saline Storage Cost Model, over the total area of any formation, only 2.5 percent of the area is assigned to structural closure or 1.25 percent each for dome and anticline structures. [19] The remaining area is regional dip (97.5 percent). Dome and anticline structures have higher storage coefficients, but the regional dip structural portion of a formation has considerably higher storage potential due to its larger areal extent. CO_2 storage potential modeled here is a resource that has yet to be proven. This process begins with site characterization for a specific storage project.

Each formation in each basin has a maximum theoretical capacity to store CO_2, and this capacity significantly exceeds the mass of CO_2 being stored by a single storage project. It is assumed that institutional issues (such as obtaining property rights to store CO_2, restrictions on storage in urban areas) and pressure interferences from multiple storage sites will reduce the effective area of a formation to provide storage capacity. The model takes into account total storage potential and the total mass of CO_2 to be injected by a single project over the time of operations and adjusts the total mass of CO_2 stored, limiting utilization of a formation to less than 60 percent.

For each basin plotted in Exhibit 3-2, the cost to store at least 25 Gt is shown in Exhibit 3-3. A storage potential of 25 Gt presents a significant resource relative to the generating capacity of the electric power sector reflected by the gigawatt (GW) storage potential in Exhibit 3-3. Choosing this point on the supply-cost curves provides a conservative estimate of the storage cost since many decades, if not more than a century, will pass before 25 Gt of CO_2 is stored in any of the four individual basins. For example, 25 Gt of storage would be sufficient for 125 GW of coal power with 90 percent CO_2 capture operating over 30 years.

Exhibit 3-3 Storage resource potential for four basins

Basin	Modeled Cost Scenario	Storage Potential to 25 Gt				Storage Potential to 50 Gt			Storage Potential to 75 Gt		
		$/tonne (2011)	Storage Potential (Gt) at this $/t	% of next 100 yrs of captured CO_2	GW Storage Potential	$/tonne (2011)	Storage Potential (Gt) at this $/t	% of next 100 yrs of captured CO_2	$/tonne (2011)	Storage Potential (Gt) at this $/t	% of next 100 yrs of captured CO_2
Illinois	Low	5.49	109	30	545	5.49	109	30	5.49	109	31
	Base	**8.69**	**96**	**27**	**482**	**8.69**	**96**	**27**	**8.69**	**96**	**27**
	High	19.65	94	26	469	19.65	94	26	19.65	94	26
East Texas	Low	5.69	45	13	227	7.82	68	19	8.08	86	24
	Base	**8.83**	**40**	**11**	**201**	**13.67**	**63**	**17**	**13.69**	**79**	**22**
	High	19.57	37	10	187	33.22	53	15	83.36	74	21
Williston	Low	8.79	106	30	534	8.79	106	30	8.79	106	30
	Base	**13.95**	**104**	**29**	**522**	**13.95**	**104**	**29**	**13.95**	**104**	**29**
	High	31.60	90	25	453	31.60	90	25	31.60	90	25
Powder River	Low	14.11	106	30	534	14.11	106	30	14.11	106	30
	Base	**21.81**	**89**	**25**	**447**	**21.81**	**89**	**25**	**21.81**	**89**	**25**
	High	46.69	68	19	340	46.69	68	19	54.94	82	23
Totals	Low		366	102	1,839		390	109		407	113
	Base		**329**	**92**	**1,652**		**352**	**98**		**368**	**102**
	High		289	81	1,450		305	85		339	95

Source: NETL

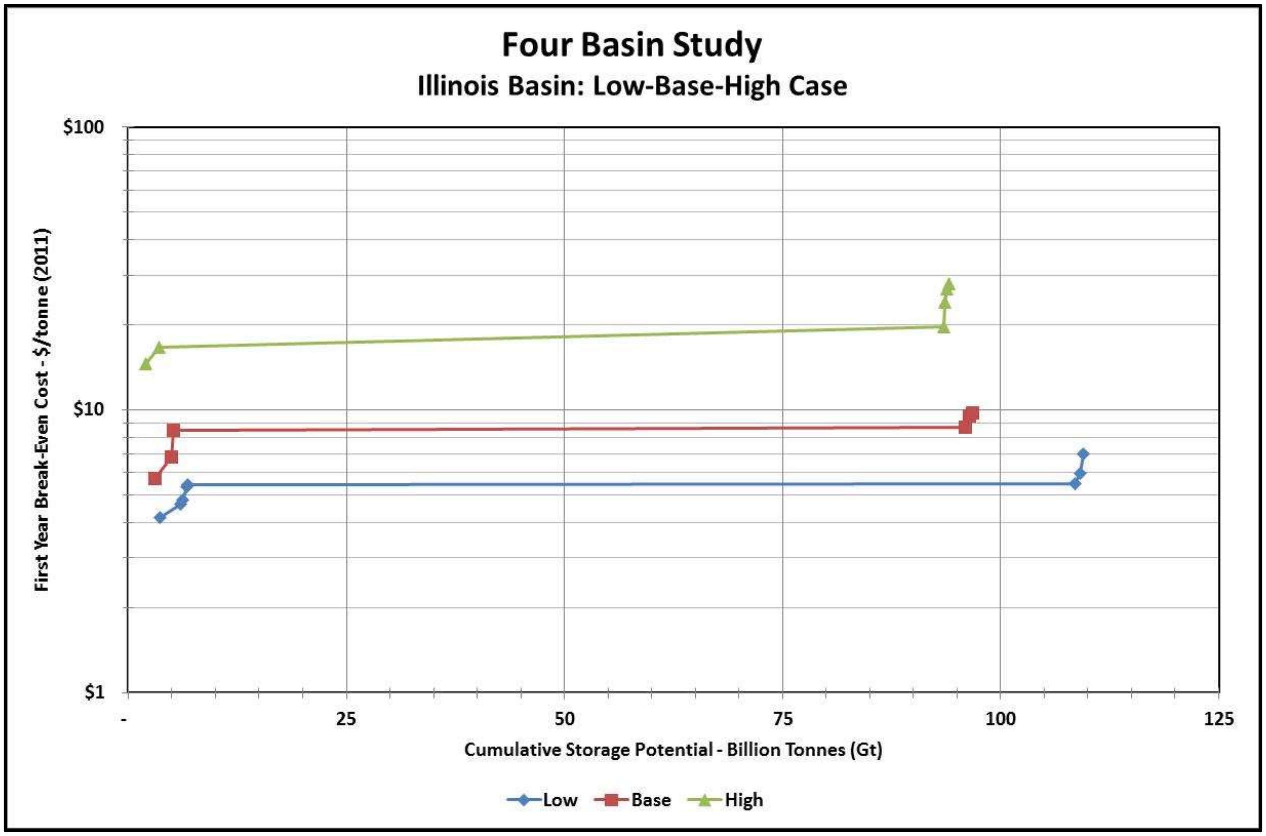
For the East Texas Basin, 25 Gt of cumulative storage resource potential is provided by a combination of sedimentary depositional and structural settings in the Woodbine and Paluxy formations, each represented by a point on the cost supply curve. For the base-cost case scenario in the East Texas Basin, the low-cost point is $6.20 per tonne of CO_2 stored for a dome structure in the Woodbine. A reservoir with regional dip structural setting in the Woodbine provides the storage resource potential at the 25 Gt mark at a cost of $8.83 per tonne of CO_2. At this price, within the Woodbine formation, the resource storage potential represents 40 Gt of captured CO_2. This storage resource potential represents 11 percent of the volume of CO_2 emissions that can be captured from the electric power and industrial sectors over the next century. Similar information for the Illinois, Powder River, and Williston Basins are also posted in Exhibit 3-3.

For these four basins, the base-cost case scenario storage resource potential at the CO_2 price associated with cumulative storage of 25 Gt totals 329 Gt. This represents 92 percent of the volume of CO_2 emissions that can be captured from the electric power and industrial sectors over the next century. Assuming 6.64 million tonnes of CO_2 captured from a 1 GW power plant (30 years of operation, 30 percent plant efficiency, 80 percent capacity factor, and 90 percent capture efficiency), this storage resource potential is equivalent to 1,652 GW of power generation.

Storage resource potential with respect to electric power generation ranges from 201 GW in the East Texas Basin to 522 GW in the Williston Basin. Total storage resource potential for these four basins, through the CO_2 price associated with cumulative storage of 75 Gt, represents 102 percent of the volume of CO_2 emissions that can be captured from the electric power and industrial sectors over the next century. The Illinois Basin, with the Mt. Simon Formation, is the low-cost provider. The Williston Basin, as illustrated in Exhibit 3-3, has the largest storage resource potential.

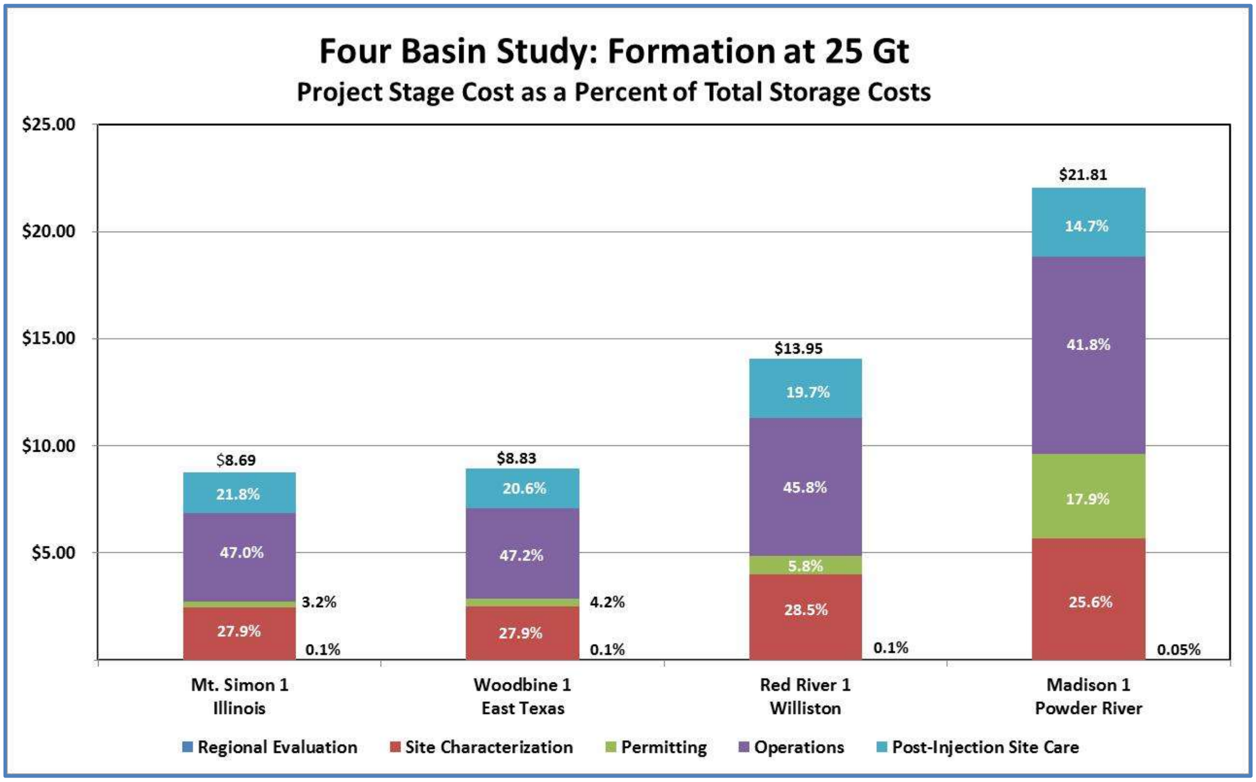
The range of storage costs for the low-cost, base, and high-cost case scenarios for the Illinois Basin is plotted in Exhibit 3-4. The regional dip portion of the Mt. Simon formation in central Illinois provides 90.2 Gt of storage potential resource. Increasing costs shifts the curves up while a reduction in storage coefficient shifts the curves to the left. The cost to store a tonne of captured CO_2 predominately lies between the low-cost and high-cost curves but this does not preclude the possibility that the storage costs of any particular project may lie above high-cost or below low-cost curves.

Exhibit 3-4 Potential storage cost supply curves for low-cost, base, and high-cost case scenarios in the Illinois Basin



Source: NETL

Exhibit 3-5 Breakout of project stage cost as a percent of total storage costs



Source: NETL

A breakout, by project stage, of storage costs for the Mt. Simon, along with the Woodbine, Red River, and Madison formations, is presented in Exhibit 3-5. This cost breakout is for the regional dip structural setting for each formation. It is this reservoir formation combination that provides the storage potential resource at 25 Gt and more (see Exhibit 3-2 and Exhibit 3-4). For each reservoir modeled (formation and structural setting), applied costs are identical (see modeling parameters Exhibit 2-5). Variables impacting costs are in the reservoir. Storage capacity and the combination of formation height, porosity, storage coefficient, and CO_2 density determine the areal extent of the plume. The areal extent of the plume determines the number of monitoring wells drilled and the extent of 3-D seismic and monitoring, verification, and accounting (MVA) coverage needed to monitor the plume. Plume size impacts costs for site characterization, operations, and post-injection site care. These costs are comparable in the Woodbine and Mt. Simon but increase for the Red River and more so for the Madison; this is due to an increasing plume size and the number of monitoring wells drilled (Exhibit 3-6). The significant change in project stage costs between reservoirs in this instance is in permitting when the injection wells are drilled and completed. Formation height and permeability impact injection of CO_2, and depth drilled impacts drilling costs. During permitting, four injection wells are drilled for the Mt. Simon, Woodbine, and Red River, but the Red River is 3,000 feet deeper accounting for the increased costs in Williston Basin storage. In the Powder River Basin, the

Madison is 2,000 feet deeper than the Red River, and 10 injection wells are drilled. This increasing depth also impacts drilling and completion costs for monitoring wells.

Exhibit 3-6 Cost items for reservoirs providing storage potential resource at 25 Gt

	Mt. Simon 1 Illinois	Woodbine 1 East Texas	Red River 1 Williston	Madison 1 Powder River
Formation Height feet	1000	700	530	883
Permeability - md	100	500	39	5
Porosity - %	12	20	14	10
Storage Coefficient - %	5.6	5.4	7.3	6.4
Number of Injection Wells	4	4	4	10
Injection Well Depth - feet	4,550	5,900	9,315	11,467
Monitoring Wells - Dual Completed	13	11	14	15
Monitoring Wells - Above Seal	9	7	10	11
Total Monitoring Wells	22	18	24	26
3-D Seismic Area - mi^2	75	73	113	131

Source: NETL

3.3 Combining Transport and Storage Costs

Exhibit 3-7 reports the base case storage cost results from the FE/NETL CO_2 Saline Storage Cost Model base-cost case for the 25 Gt of cumulative storage resource potential and transport cost for the example plant parameters. The cost from the FE/NETL CO_2 Transport Cost Model of transporting CO_2 100 km is also provided in Exhibit 3-7. The resulting CO_2 T&S values (rounded to the nearest whole dollar) to be used in NETL systems studies are shown in the far right column.

Exhibit 3-7 Total transport and base case storage (T&S) costs for use in NETL system studies

Plant Location	Basin	Transport (2011$/tonne)	Base Case Storage (2011$/tonne)	Total T&S (2011$/tonne)	T&S Value for System Studies (2011$/tonne)
Midwest	Illinois	2.24	8.69	10.93	11
Texas	East Texas		8.83	11.07	11
North Dakota	Williston		13.95	16.19	16
Montana	Powder River		21.81	24.05	24

4 Revision Control

Exhibit 4-1 Revision table

Revision Number	Revision Date	Description of Change	Comments
1	September 30, 2013	Updated cost estimates	
2	February 12, 2014	Document edited and formatted	

5 References

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